Report #:DOE/EIA-0554(2007)
Release date: April 2007
Next release date: March 2008

Coal Market Module

The NEMS Coal Market Module (CMM) provides forecasts of U.S. coal production, consumption, exports, imports, distribution, and prices. The CMM comprises three functional areas: coal production, coal distribution, and coal exports. A detailed description of the CMM is provided in the EIA publication, *Coal Market Module of the National Energy Modeling System 2007,* DOE/EIA-M060(2007) (Washington, DC, 2007*).*

Key Assumptions

Coal Production

The coal production submodule of the CMM generates a different set of supply curves for the CMM for each year of the forecast. Forty separate supply curves are developed for each of 14 supply regions, nine coal types (unique combinations of thermal grade and sulfur content), and two mine types (underground and surface). Supply curves are constructed using an econometric formulation that relates the minemouth prices of coal for the supply regions and coal types to a set of independent variables. The independent variables include: capacity utilization of mines, mining capacity, labor productivity, the user cost of capital of mining equipment, and the cost of factor inputs (labor and fuel).

The key assumptions underlying the coal production modeling are:

- As capacity utilization increases, higher minemouth prices for a given supply curve are projected. The opportunity to add capacity is allowed within the modeling framework if capacity utilization rises to a pre-determined level, typically in the 80 percent range. Likewise, if capacity utilization falls, mining capacity may be retired. The amount of capacity that can be added or retired in a given year depends on the level of capacity utilization, the supply region, and the mining process (underground or surface). The volume of capacity expansion permitted in a forecast year is based upon historical patterns of capacity additions.

- Between 1980 and 1999, U.S. coal mining productivity increased at an average rate of 6.7 percent per year from 1.93 to 6.61 tons per miner per hour. The major factors underlying these gains were interfuel price competition, structural change in the industry, and technological improvements in coal mining.[106] Since 1999, however, growth in overall U.S. coal mining productivity has slowed substantially, decreasing at a rate of 0.6 percent per year to 6.36 tons per miner hour in 2005. By region, productivity in most of the coal producing basins represented in the CMM has remained essentially constant during the past 5 years. In the Central Appalachian coal basin, which has been mined extensively, productivity declined by a significant 24 percent between 1999 and 2005, corresponding to an average decline of 4.4 percent per year.

  Over the forecast period, labor productivity is expected to remain near current levels in most coal supply regions, reflecting the trend of the previous five years. Higher stripping ratios and the added labor needed to maintain more extensive underground mines offset productivity gains achieved from improved equipment, automation, and technology. Productivity in some areas of the East is projected to decline as operations move from mature coalfields to marginal reserve areas. Regulatory restrictions on surface mines and fragmentation of underground reserves limit the benefits that can be achieved by Appalachian producers from economies of scale.

  In the CMM, different rates of productivity improvement are assumed for each of the 40 coal supply curves used to represent U.S. coal supply. These estimates are based on recent historical data and expectations regarding the penetration and impact of new coal mining technologies.[107] Data on labor productivity are provided on a quarterly and annual basis by individual coal mines and preparation plants on the U.S. Mine Safety and Health Administration's Form 7000-2, "Quarterly Mine Employment and Coal Production Report" and the Energy Information Administration's Form EIA-7A, *Coal Production Report*. In the reference case, overall U.S. coal mining labor productivity increases at rate of 0.8 percent a year between 2005 and 2030. Reference case projections of coal mining productivity by region are provided in Table 67.

- In the *AEO2007* forecast scenarios, both the wage rate for U.S. coal miners and mine equipment costs are assumed to remain constant in 2005 dollars (i.e., increase at the general rate of inflation) over the forecast period. This assumption primarily reflects the recent trends in these cost variables. Although U.S. coal mining wages declined by 1.1 percent per year between 1990 and 2001 (in 2005 dollars)[108], they have remained essentially constant since then. The producer price index (PPI) for mining machinery and equipment has remained relatively constant over the past decade, rising from 177.0 (2005 dollars) in 1990 to 181.2 in 2005.[109]

Coal Distribution

The coal distribution submodule of the CMM determines the least-cost (minemouth price plus transportation cost) supplies of coal by supply region for a given set of coal demands in each demand sector using a linear programming algorithm. Production and distribution are computed for 14 supply (Figure 10) and 14 demand regions (Figure 11) for 49 demand subsectors.

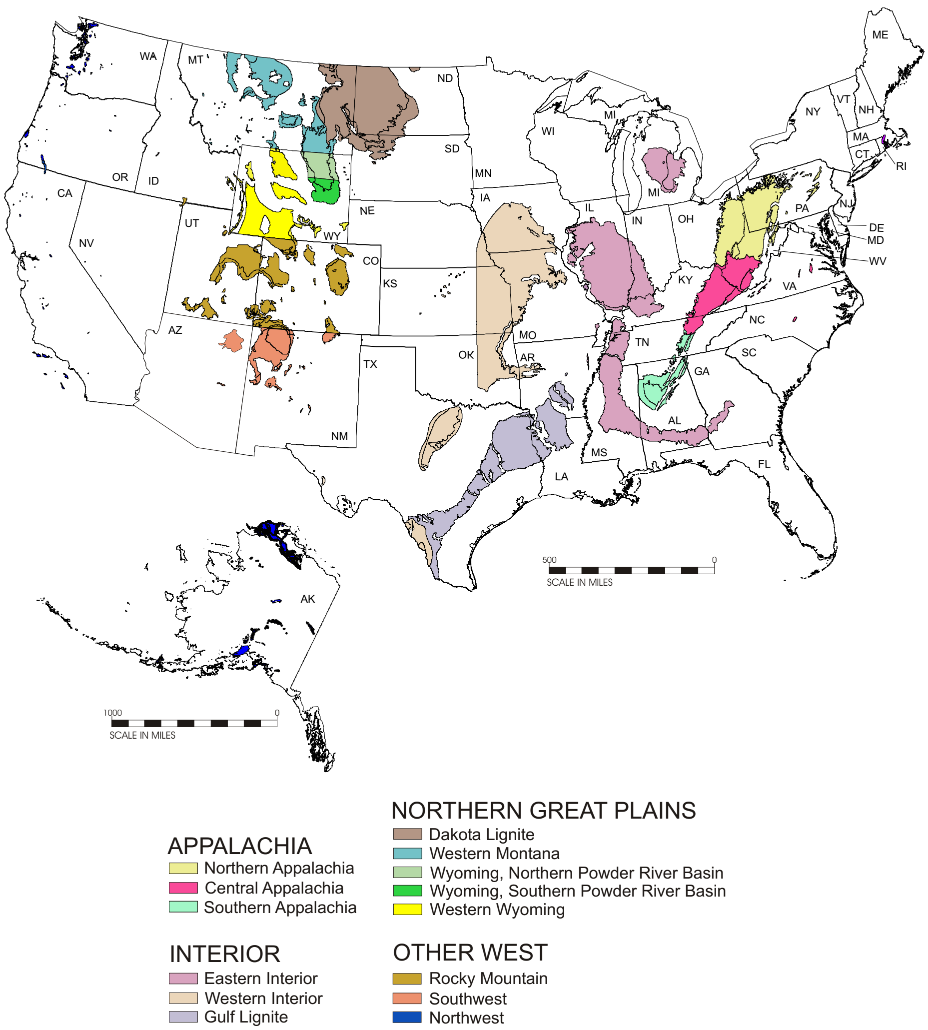
Table 67. Coal Mining Productivity by Region
(Short Tons per Miner Hour)

Supply Region	2005	2010	2015	2020	2025	2030	Average Annual Growth 05-30
Northern Appalachia	4.05	3.89	4.04	4.07	4.10	4.15	0.1%
Central Appalachia	3.07	2.74	2.66	2.56	2.49	2.39	-1.0%
Southern Appalachia	2.18	2.12	2.03	1.96	1.90	1.83	-0.7%
Eastern Interior	4.33	4.65	4.75	4.85	4.83	4.87	0.5%
Western Interior	4.12	4.13	4.13	4.13	4.13	4.13	0.0%
Gulf Lignite	9.53	9.29	9.06	8.84	8.62	8.41	-0.5%
Dakota Lignite	16.80	17.10	17.54	17.98	18.43	18.90	0.5%
Western Montana	23.39	25.46	24.50	22.09	21.53	20.98	-0.4%
Wyoming, Northern Power River Basin	41.79	42.76	43.45	43.93	44.33	44.55	0.3%
Wyoming, Southern Power River Basin	43.46	43.24	42.90	42.38	41.71	40.88	-0.2%
Western Wyoming	9.32	9.13	9.36	9.57	9.62	9.66	0.1%
Rocky Mountain	7.52	7.50	7.67	7.82	7.94	8.05	0.3%
Arizona/New Mexico	9.19	9.30	9.43	9.49	9.55	9.58	0.2%
Alaska/ Washington	4.11	4.13	4.13	4.13	4.13	4.13	0.0%
U.S. Average	6.36	6.47	6.80	7.18	7.75	7.84	0.8%

Source: Projections: Energy Information Administration, Office of Integrated and Forecasting.

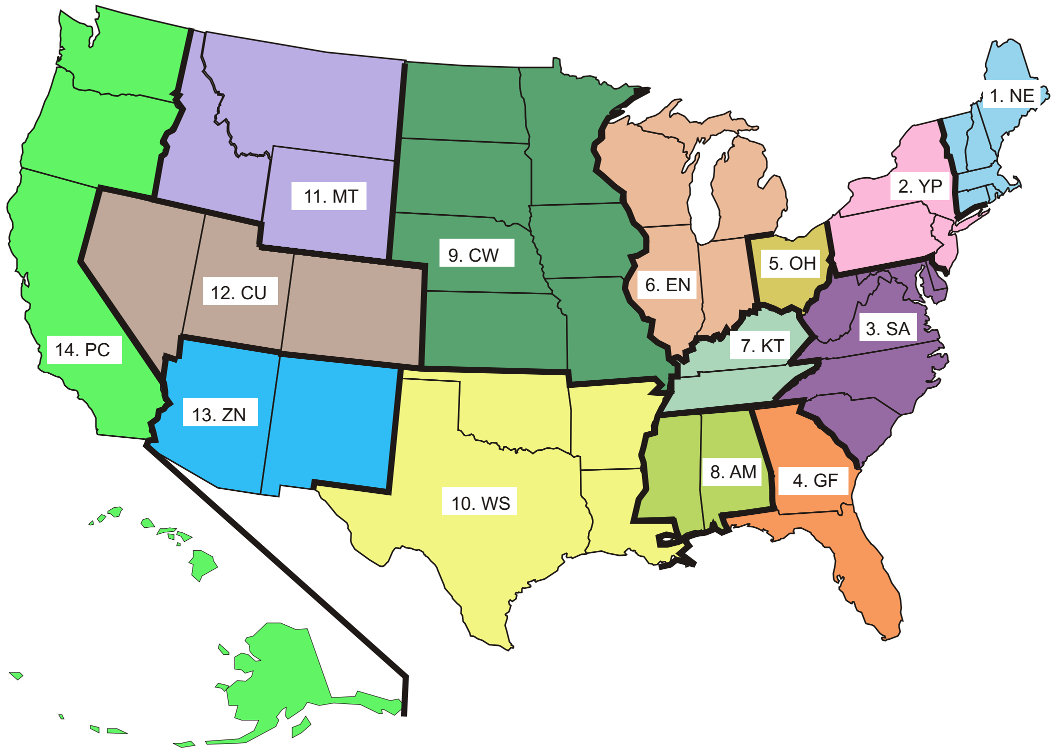
The projected levels of coal-to-liquids, industrial steam, coking, and residential/commercial coal demand are provided by the petroleum market, industrial, commercial, and residential demand modules, respectively; electricity coal demands are forecasted by the EMM; coal imports and coal exports are forecasted by the CMM based on non-U.S. coal supply availability, endogenously determined U.S. import demand, and exogenously determined world coal demand (non-U.S.).

Figure 10. Coal Supply Regions



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting

Figure 11. Coal Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. SA	WV,MD,DC,DE,VA,NC,SC
4. GF	GA,FL
5. OH	OH
6. EN	IN,IL,MI,WI
7. KT	KY,TN

Region Code	Region Content
8. AM	AL,MS
9. CW	MN,IA,ND,SD,NE,MO,KS
10. WS	TX,LA,OK,AR
11. MT	MT,WY,ID
12. CU	CO,UT,NV
13. ZN	AZ,NM
14. PC	AK,HI,WA,OR,CA

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

The key assumptions underlying the coal distribution modeling are:

- Base-year (2005) transportation costs are estimates of average transportation costs for each origin-destination pair without differentiation by transportation mode (rail, truck, barge, and conveyor). These costs are computed as the difference between the average delivered price for a demand region (by sector and for export) and the average minemouth price for a supply curve. Delivered price data are from Form EIA-3, *Quarterly Coal Consumption Report-Manufacturing Plants*, Form EIA-5, *Quarterly Coke Consumption* and *Quality Report, Coke Plants*, Form EIA-423, *Monthly Cost and Quality of Fuels for Electric Plants Report*, Federal Energy Regulatory Commission (FERC) Form 423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*, and the U.S. Bureau of the Census' Monthly Report EM-545. Minemouth price data are from Form EIA-7A, *Coal Production Report*.

- For the electricity sector only, a two-tier transportation rate structure is used for those regions which, in response to rising demands or changes in demands, may expand their market share beyond historical levels. The first-tier rate is representative of the historical average transportation rate. The second-tier transportation rate is used to capture the higher cost of expanded shipping distances in large demand regions. The second tier is also used to capture costs associated with the use of subbituminous coal at units that were not originally designed for its use. This cost is estimated at $0.10 per million Btu (2000 dollars).[110]

- Coal transportation costs, both first- and second-tier rates, are modified over time by two regional (east and west) transportation indices. The indices are measures of the change in average transportation rates, on a tonnage basis, that occurs between successive years for rail and multi-mode coal shipments. An east index is used for coal originating from eastern supply regions while a west index is used for coal originating from western supply regions. The indices are calculated econometrically as a function of railroad productivity, the user cost of capital of railroad equipment, average contract duration, and average distance (west only). Although the indices are derived from railroad information, they are universally applied to all domestic coal transportation movements within the CMM. In the *AEO2007* reference case, eastern coal transportation rates are projected to rise by 4 percent between 2005 and 2030, and western rates are projected to rise by 3 percent.

  Railroad productivity, measured in freight ton-miles per employee per year, is expected to increase at an average rate of 1.4 percent per year for the east and 1.4 percent per year for the west from 2005. The user cost of capital for railroad equipment is calculated from the PPI for railroad equipment, projected exogenously to decrease by 0.2 percent per year in real terms, and accounts for the opportunity cost of money used to purchase equipment, depreciation occurring as a result of use of the equipment (assumed at 10 percent), less any capital gain associated with the worth of the equipment. Contract duration is held constant at 2001 levels over the forecast reflecting the assumption that new contracts will continue to be, on average, less than 5 years in length. For the west, distance is held constant over the forecast reflecting that distance is already implicitly accounted for in the model by using the origin-destination pair transportation rate structure. The transportation rate indices for seven *AEO2007* cases are shown in Table 68.

Table 68. Transportation Rate Multipliers
(Constant Dollar Index, 2005=1.000)

Scenario	Region:	2005	2010	2015	2020	2025	2030
Reference Case	East	1.000	1.0863	1.0641	1.0589	1.0497	1.0422
	West	1.000	1.0627	1.0459	1.0415	1.0342	1.0283
High Resource Price	East	1.000	1.0869	1.0634	1.0606	1.0545	1.0475
	West	1.000	1.0631	1.0454	1.0427	1.0377	1.0322
Low Resource Price	East	1.000	1.0856	1.0650	1.0589	1.0477	1.0394
	West	1.000	1.0622	1.0465	1.0414	1.0328	1.0262
High Economic Growth	East	1.000	1.0868	1.0680	1.0681	1.0644	1.0605
	West	1.000	1.0630	1.0487	1.0482	1.0449	1.0416
Low Economic Growth	East	1.000	1.0859	1.0603	1.0506	1.0375	1.0266
	West	1.000	1.0624	1.0431	1.0354	1.0253	1.0169
High Coal Cost	East	1.000	1.0903	1.0860	1.1000	1.1096	1.1210
	West	1.000	1.0661	1.0630	1.0730	1.0800	1.0884
Low Coal Cost	East	1.000	1.0819	1.0427	1.0193	0.9935	0.9683
	West	1.000	1.0590	1.0292	1.0108	0.9907	0.9710

Source: Projections: Energy Information Administration, Office of Integrated Analysis and Forecasting. Based on methodology described in *Coal Market Module of the National Energy Modeling System, Model Documentation 2007*, DOE/EIA-060(2007), (Washington, DC, 2007).

- Major coal rail carriers have implemented fuel surcharge programs in which higher transportation fuel costs have been passed on to shippers. While the programs vary in their design, the Surface Transportation Board (STB), the regulatory body with limited authority to oversee rate disputes, has recommended that the railroads agree to develop some consistencies among their disparate programs and has likewise recommended closely linking the charges to actual fuel use. The STB has cited the use of a mileage-based program as one means to more closely estimate actual fuel expenses.

  For *AEO07*, representation of a fuel surcharge program has been incorporated into the coal transportation costs. The methodology is based on BNSF Railway Company's mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $1.25 per gallon. For every $0.06 cent per gallon increase above $1.25, a $0.01 per carload mile is charged. The number of tons per carload and the number of miles vary with each supply and demand region combination and are a pre-determined model input. The final calculated surcharge (in constant dollars per ton) is added to the escalator-adjusted transportation rate.

- Coal contracts in the CMM represent a minimum quantity of a specific electricity coal demand that must be met by a unique coal supply source prior to consideration of any alternative sources of supply. Base-year (2005) coal contracts between coal producers and electricity generators are estimated on the basis of receipts data reported by electric utilities on FERC Form 423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*, and by nonutility generators on Form EIA-423, *Monthly Cost and Quality of Fuels for Electric Plants Report*. Coal contracts are specified by CMM supply region, coal type, demand region, and whether or not a unit has flue gas desulfurization equipment. Coal contract quantities are reduced over time on the basis of contract duration data reported by electric utilities on FERC Form 580, "Interrogatory on Fuel and Energy Purchase Practices," historical patterns of coal use, and information obtained from various coal and electric power industry publications and reports.

- Electric generation demand received by the CMM is subdivided into "coal groups" representing demands for different sulfur and thermal heat content categories. This process allows the CMM to determine the economically optimal blend of different coals to minimize delivered cost, while meeting emissions requirements . Similarly, nongeneration demands are subdivided into subsectors with their own coal groups to ensure that, for example, lignite is not used to meet a coking coal demand.

- Coal-to-liquids (CTL) facilities are assumed to be economic when low-sulfur distillate prices reach high enough levels. These plants are assumed to be co-production facilities located near coal mines with generation capacity of 758 MW and the capability of producing 33,200 barrels of liquid fuel per day. The technology assumed is similar to an integrated gasification combined cycle, first converting the coal feedstock to gas, and then subsequently converting the syngas to liquid hydrocarbons using the Fisher-Tropsch process. Of the total amount of coal consumed at each plant, 49 percent of the energy input is retained in the product with the remaining energy used for conversion (20 percent) and for the production of power sold to the grid (31 percent).

Coal Imports and Exports

Coal imports and exports are modeled as part of the CMM's linear program that provides annual forecasts of U.S. steam and metallurgical coal exports, in the context of world coal trade. The linear program determines the pattern of world coal trade flows that minimize the production and transportation costs of meeting U.S. import demand and a pre-specified set of regional world coal import demands. It does this subject to constraints on export capacity and trade flows.

The CMM projects steam and metallurgical coal trade flows from 17 coal-exporting regions of the world to 20 import regions for three coal types (coking, bituminous steam, and subbituminous). It includes five U.S. export regions and four U.S. import regions.

The key assumptions underlying coal export modeling are:

- The coal market is competitive. In other words, no large suppliers or groups of producers are able to influence the price through adjusting their output. Producers' decisions on how much and who they supply are driven by their costs, rather than prices being set by perceptions of what the market can bear. In this situation, the buyer gains the full consumer surplus.

- Coal buyers (importing regions) tend to spread their purchases among several suppliers in order to reduce the impact of potential supply disruptions, even though this may add to their purchase costs. Similarly, producers choose not to rely on any one buyer and instead endeavor to diversify their sales.

- Coking coal is treated as homogeneous. The model does not address quality parameters that define coking coals. The values of these quality parameters are defined within small ranges and affect world coking coal flows very little.

Data inputs for coal trade modeling:

- U.S. coal exports are determined, in part, by the projected level of world coal import demand. World steam and metallurgical coal import demands for the *AEO2007* forecast cases are shown in Tables 69 and 70.

- Step-function coal export supply curves for all non-U.S. supply regions. The curves provide estimates of export prices per metric ton, inclusive of minemouth and inland freight costs, as well as the capacities for each of the supply steps.

- Ocean transportation rates (in dollars per metric ton) for feasible coal shipments between international supply regions and international demand regions. The rates take into account maximum vessel sizes that can be handled at export and import piers and through canals and reflect route distances in thousands of nautical miles.

Coal Quality

Each year the values of base year coal production, heat, sulfur and mercury (Hg) content and carbon dioxide emissions for each coal source in CMM are calibrated to survey data. Surveys used for this purpose are the FERC Form 423, a survey of the origin, cost and quality of fossil fuels delivered to electric utilities, the Form EIA 423, a survey of the origin, cost and quality of fossil fuels delivered to non-utility generating facilities, the Form EIA-5 which records the origin, cost, and quality of coal receipts at domestic coke plants, and the Form EIA 3, which records the origin, cost and quality of coal delivered to domestic industrial consumers. Estimates of coal quality for the export and residential/commercial sectors are made using the survey data for coal delivered to coking coal and industrial steam coal consumers. Hg content data for coal by supply region and coal type, in units of pounds of Hg per trillion Btu, shown in Table 71, were derived from shipment-level data reported by electricity generators to the Environmental Protection Agency in its 1999 Information Collection Request. The database included approximately 40,500 Hg samples reported for 1,143 generating units located at 464 coal-fired facilities. Carbon dioxide emission factors for each coal type are shown in Table 73 in pounds of carbon dioxide emitted per million Btu.[111]

Table 69. World Steam Coal Import Demand by Import Region
(Million metric tons of coal equivalent)

Import Regions[1]	2005[2]	2010	2015	2020	2025	2030
The Americas	50.6	51.6	56.5	86.5	93.1	108.6
United States[3]	23.1	29.8	33.7	58.9	64.5	77.8
Canada	13.5	7.3	6.8	6.9	7.5	7.8
Mexico	6.0	5.8	6.9	9.5	9.5	9.5
South America	8.1	8.7	9.1	11.2	11.6	13.6
Europe	157.3	163.4	160.6	157.7	151.3	149.8
Scandinavia	9.6	10.3	7.5	6.5	5.7	4.9
U.K/Ireland	35.7	35.0	33.8	33.0	32.4	31.6
Germany/Austria	25.2	26.7	28.1	27.8	26.8	25.8
Other NW Europe	23.8	19.8	17.9	16.9	14.9	13.9
Iberia	22.9	22.7	21.4	20.3	19.0	17.4
Italy	13.6	23.2	25.0	26.8	26.8	26.8
Med/E Europe	26.5	25.7	26.9	26.4	25.7	29.4
Asia	252.2	294.6	319.4	341.6	376.5	409.7
Japan	88.8	86.3	83.4	82.6	85.8	88.5
East Asia	94.8	123.2	133.2	141.0	154.6	169.4
China/Hong Kong	24.9	31.4	38.4	42.4	48.8	55.9
ASEAN	20.6	28.5	35.5	43.9	53.5	60.9
Indian Sub	23.1	25.2	28.9	31.7	33.8	35.0
Total	460.1	509.6	536.5	585.8	620.9	668.1

[1]Import Regions: **South America:** Argentina, Brazil, Chile, Puerto Rico; **Scandinavia:** Denmark, Finland, Norway, Sweden; **Other NW Europe:** Belgium, France, Luxembourg, Netherlands; **Iberia:** Portugal, Spain; **Med/E Europe:** Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; **East Asia:** North Korea, South Korea, Taiwan; **ASEAN:** Malaysia, Philippines, Thailand; **Indian Sub:** Bangladesh, India, Iran, Pakistan, Sri Lanka.

[2]The base year of the world trade forecast for coal is 2005.

[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.

Notes: One “metric ton of coal equivalent” contains 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

Table 70. World Metallurgical Coal Import Demand by Import Region
(Million metric tons of coal equivalent)

Import Regions[1]	2005[2]	2010	2015	2020	2025	2030
The Americas	20.1	26.1	26.9	28.4	30.4	34.9
United States	1.2	1.3	1.3	1.3	1.3	1.3
Canada	4.4	3.9	3.8	3.6	3.4	3.3
Mexico	1.0	1.6	1.7	1.9	2.0	2.2
South America	13.4	19.3	20.1	21.6	23.6	28.1
Europe	57.9	50.3	48.4	51.6	53.5	54.9
Scandinavia	3.7	2.5	2.1	1.9	1.6	1.3
U.K/Ireland	8.9	6.8	6.8	6.8	6.8	6.8
Germany/Austria	6.1	6.6	6.6	6.6	6.6	6.5
Other NW Europe	16.2	14.2	12.6	11.5	11.0	11.1
Iberia	5.3	3.9	3.8	3.8	3.8	3.8
Italy	8.3	6.2	5.7	5.7	5.7	5.6
Med/E Europe	9.4	10.1	10.8	15.3	18.0	19.8
Asia	123.7	138.5	149.3	160.4	172.2	184.2
Japan	73.3	68.1	66.4	64.7	63.7	62.8
East Asia	26.3	24.8	25.3	27.8	30.1	32.5
China/Hong Kong	4.3	20.0	28.7	35.9	43.9	52.0
ASEAN	0.0	0.0	0.0	0.0	0.0	0.0
Indian Sub	19.8	25.6	28.9	32.0	34.5	36.9
Total	201.7	214.9	224.6	240.4	256.1	274.0

[1]Import Regions: **South America:** Argentina, Brazil, Chile, Puerto Rico; **Scandinavia:** Denmark, Finland, Norway, Sweden; **Other NW Europe:** Belgium, France, Luxembourg, Netherlands; **Iberia:** Portugal, Spain; **Med/E Europe:** Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; **East Asia:** North Korea, South Korea, Taiwan; **ASEAN:** Malaysia, Philippines, Thailand; **Indian Sub:** Bangladesh, India, Iran, Pakistan, Sri Lanka.

[2] The base year of the world trade forecast for coal is 2005.

Notes: One "metric ton of coal equivalent" contains 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

Source: Projections: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 71. Production, Heat Content, and Sulfur, Mercury and Carbon Dioxide Emission Factors by Coal Type and Region

Coal Supply Region	Coal Rank and Sulfur Level	Mine Type	2005 Production (Million Short tons)	Heat Content (Million Btu per Short Ton)	Sulfur Content (Pounds Per Million Btu)	Mercury Content (Pounds Per Trillion Btu)	CO_2 (Pounds Per Million Btu)
Northern Appalachia	Metallurgical	Underground	3.5	27.43	0.74	N/A	205.4
	Mid-Sulfur Bituminous	All	75.0	25.16	1.28	11.17	205.4
	High-Sulfur Bituminous	All	61.6	24.69	2.52	11.67	203.6
	Waste Coal (Gob and Culm)	Surface	13.4	12.08	2.75	63.9	203.6
Central Appalachia	Metallurgical	Underground	39.2	27.43	0.63	N/A	203.8
	Low-Sulfur Bituminous	All	47.1	24.92	0.54	5.61	203.8
	Mid-Sulfur Bituminous	All	149.4	24.55	0.92	7.58	203.8
Southern Appalachia	Metallurgical	Underground	8.1	27.43	0.51	N/A	203.3
	Low-Sulfur Bituminous	All	0.5	24.82	0.53	3.87	203.3
	Mid-Sulfur Bituminous	All	12.9	25.13	1.24	10.15	203.3
East Interior	Mid-Sulfur Bituminous	All	29.3	22.49	1.05	5.6	202.9
	High-Sulfur Bituminous	All	63.6	22.83	2.64	6.35	202.6
	Mid-Sulfur Lignite	Surface	3.6	10.19	0.91	14.11	211.4
West Interior	High-Sulfur Bituminous	Surface	2.6	22.74	2.30	21.55	202.4
Gulf Lignite	Mid-Sulfur Lignite	Surface	23.3	13.32	1.25	14.11	211.4
	High-Sulfur Lignite	Surface	26.8	12.98	2.28	15.28	211.4
Dakota Lignite	Mid-Sulfur Lignite	Surface	30.3	13.27	1.06	8.38	216.6
Western Montana	Low-Sulfur Subbituminous	Underground	0.2	20.90	0.48	5.06	207.5
	Low-Sulfur Subbituminous	Surface	20.4	18.69	0.38	5.06	211.3
	Mid-Sulfur Subbituminous	Surface	19.4	17.17	0.77	5.47	211.3
Northern Wyoming	Low-Sulfur Subbituminous	Surface	149.0	16.89	0.39	7.08	210.6
	Mid-Sulfur Subbituminous	Surface	3.6	16.22	0.79	7.55	210.6
Southern Wyoming	Low-Sulfur Subbituminous	Surface	237.5	17.62	0.32	5.22	210.6
Western Wyoming	Low-Sulfur Subbituminous	Underground	0.4	18.78	0.46	2.19	204.4
	Low-Sulfur Subbituminous	Surface	3.6	18.95	0.51	4.06	210.6
	Mid-Sulfur Subbituminous	Surface	10.2	19.24	0.73	4.35	210.6
Rocky Mountain	Low-Sulfur Bituminous	Underground	53.0	22.97	0.48	3.82	203.0
	Low-Sulfur Subbituminous	Surface	10.1	20.51	0.41	2.04	210.6
Southwest	Low-Sulfur Bituminous	Surface	17.4	21.25	0.47	4.66	205.4
	Mid-Sulfur Subbituminous	Surface	15.3	18.02	0.93	7.18	206.7
	Mid-Sulfur Bituminous	Underground	7.9	19.23	0.80	7.18	206.7
Northwest	Mid-Sulfur Subbituminous	Surface	6.7	15.66	0.92	6.99	207.9

N/A = not available.

*Indicates that the quantity is less than 50,000 short tons.

Source: Energy Information Administration, Form EIA-3, "Quarterly Coal Consumption Report—Manufacturing Plants"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report—Annual"; Form EIA-7A, "Coal Production Report", and Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report." Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM-545." U.S. Environmental Protection Agency, Emission Standards Division, *Information Collection Request for Electric Utility Steam Generating Unit, Mercury Emissions Information Collection Effort* (Research Triangle Park, NC, 1999). B.D. Hong and E.R. Slatick, "Carbon Dioxide Emission Factors for Coal," in Energy Information Administration, *Quarterly Coal Report*, January-March 1994, DOE/EIA-0121 (94/Q1) (Washington, DC, August 1995).

Legislation

The *AEO2007* reference forecast incorporates provisions of the Clean Air Act Amendments of 1990 as they apply to sulfur dioxide and nitrogen oxide emissions. EPA finalized the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) in March 2005, and both are represented in the reference forecast. For affected states, CAIR further restricts emissions of sulfur dioxide beginning in 2010 to 3.6 million tons and nitrogen oxides beginning in 2009 to 1.5 million tons. Beginning in 2015, for affected states, tighter emission limits for sulfur dioxide (2.5 million tons) and nitrogen oxides (1.3 million tons) are required in Phase 2 of CAIR. A nationwide cap for mercury of 38 tons per year beginning in 2010 and then 15 tons per year beginning in 2018 are specified in CAMR. The reference case excludes any potential environmental actions not currently mandated such as carbon dioxide reductions or other rules or regulations not finalized.

Coal Cost Cases

In the reference case, coal mine labor productivity is assumed to increase on average by 0.8 percent per year through 2030 while miner wage rates and mine equipment costs remain constant in 2005 dollars. Eastern and western railroad productivity is assumed to grow at an average rate of 1.4 percent from 2005. Railroad equipment costs are assumed to decline on average by 0.2 percent per year from 2005. In two alternative coal cost cases, productivity, average miner wages, and equipment cost assumptions were modified for 2007 through 2030 in order to examine the impacts on U.S. coal supply, demand, distribution and prices.

In the low mining cost case, coal mine labor productivity is assumed to increase at an average rate of 3.4 percent per year through 2030. Miner wages are assumed to decline in constant dollars by 1.0 percent per year. Mine equipment costs and railroad equipment costs are projected to fall by 1.0 and 1.2 percent, respectively. In the low mining cost case, eastern and western railroad productivity is assumed to grow at an average rate of 3.6 percent from 2005.

In the high mining cost case, coal mine labor productivity is assumed to decline at an average rate of 2.5 percent per year through 2030. Miner wages are assumed to increase in constant dollars by 1.0 percent per year. Mine equipment costs and railroad equipment costs are projected to increase by 1.0 and 0.7 percent, respectively. In the high mining cost case, eastern and western railroad productivity is assumed to decline at an average rate of 0.9 and 0.8 percent from 2005, respectively.

For the coal cost cases, adjustments to the reference case coal mining and railroad productivity assumptions were based on variations in growth rates observed in the data for these industries since 1980. The low and high coal cost cases represent fully integrated NEMS runs, with feedback from the Macroeconomic Activity, International, supply, conversion, and end-use demand modules.

Notes and Sources

[106] Energy Information Administration, The U.S. Coal Industry, 1970-1990: Two Decades of Change, DOE/EIA-0559, (Washington, DC, November 1992).

[107] Stanley C. Suboleski, et.al., Central Appalachia: Coal Mine Productivity and Expansion, Electric Power Research Institute, EPRI IE-7117, (September 1991).

[108] U.S. Department of Labor, Bureau of Labor Statistics, Series ID: CEU1021210006.

[109] U.S. Department of Labor, Bureau of Labor Statistics, Series ID: PCU333131333131.

[110] The estimated cost of switching to subbituminous coal, $0.10 per million Btu (2000 dollars), was derived by Energy Ventures Analysis, Inc. and was recommended for use in the CMM as part of an Independent Expert Review of the Annual Energy Outlook 2002's Powder River Basin production and transportation rates. Barbaro, Ralph and Seth Schwartz. *Review of the Annual Energy Outlook 2002 Reference Case Forecast for PRB Coal*, prepared for the Energy Information Administration (Arlington, VA: Energy Ventures Analysis, Inc., August 2002)

[111] Hong, B.D. and Slatick, E.R. “Carbon Dioxide Emission Factors for Coal,” Energy Information Administration, Quarterly Coal Report, January-March 1994, DOE/EIA-121 (94/Q1) (Washington, DC, August 1995).